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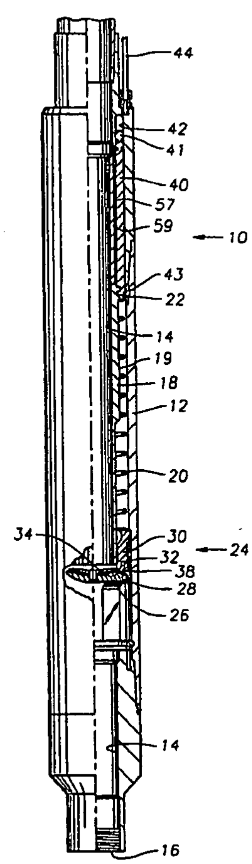
(54) Title: COATED DOWNHOLE TOOLS

(57) Abstract

Coated downhole tools (10, 110, 208, 310) are provided to control the flow of fluids through a well conduit, wherein a fluorinated ethylene propylene coating prevents or retards deposition of scale, solids, or other precipitates on the coated downhole tool metallic surfaces (19, 32, 68, 70, 131, 215, 230, 232, 235, 367).



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COATED DOWNHOLE TOOLS

RELATED APPLICATIONS

This application claims the benefit of U. S. Provisional Application No. 60/081,170, filed April 9, 1998.

BACKGROUND OF THE INVENTION

1. Field Of The Invention

The present invention relates to subsurface or downhole tools used in onshore and offshore drilling and production. More specifically the present invention relates to downhole tools which are coated to reduce fouling on metallic parts by scale, solids deposition and other precipitates such as corrosion products, salts, clay, friable sands, paraffins, asphaltenes, and the like within a well bore.

2. Description Of The Related Art

It is known that after an oil and gas well has been drilled it is completed by lining it with a string of casing that is cemented in place and then perforated adjacent a production zone containing hydrocarbon fluids. The hydrocarbon fluids flow through the casing perforations and into a well conduit, or production tubing, positioned within the casing. The well conduit and the casing form an annulus therebetween. Downhole tools known as packers are used to seal the annulus and force the produced fluid into the well conduit. The use of the term well conduit in the specification and claims includes, but is not limited to, off-shore well conduit, on-shore well conduit, oil well conduit, gas well conduit, water well conduit, injection well conduit, and gas lift well conduit. It is also known that a downhole tools, such as safety valves, sliding sleeves, gas lift valves and subsurface locks, may be used to provide a variety of services in the well conduit.

Subsurface safety valves are commonly used in wells to prevent uncontrolled fluid flow through the well in the event of an emergency, such as to prevent a well blowout. Conventional safety valves use a flapper which is biased by a spring to a normally closed position, but is retained in an open position by the application of hydraulic fluid from the earth's surface. The hydraulic fluid actuates a piston which, in turn, forces a flow tube downwardly which actuates the flapper. For example, when the hydraulic pressure applied to the piston exceeds the force needed to compress the spring, the piston is forced downwardly, causing the flow tube to contact and open the flapper, allowing the fluid to flow. However, when the hydraulic pressure applied is decreased, as by command from the earth's surface or by the control conduit being damaged, the spring forces the piston and the flow tube upward and away from the flapper. The flapper is then able to seat against an annular sealing surface and prevent fluid flow into the well conduit. The metallic parts of the safety valve are carefully machined and designed to facilitate smooth operation. For example, sliding components such as the piston and flowtube which vertically slide along the outside diameter of the piston protector sleeve are optimized geometrically and have carefully designed clearances. Nevertheless, scale and other deposits can come out of solution or otherwise build up on the metallic parts resulting in sticking, galling or even preventing the safety valve from closing. Operational problems, such as sticking, can also occur during the reopening of the safety valve. Production problems may result if the safety valve sticks shut following planned safety tests.

In addition, subsurface safety valves may optionally have a lock-out choke. Lock-out chokes may be used to permanently lock a subsurface safety valve in the open position. The flowtube and lock-out choke slide vertically along each other. Scale and other deposits that may come out of solution or otherwise build up on the sliding metallic surfaces may result in sticking or galling that could prevent the operation of the lock-out choke.

Another well-known downhole tool that can be selectively opened and closed, is a sliding sleeve. Sliding sleeves allow communication between the well conduit and casing annulus. Sliding sleeves may be connected in series with the tubing string to control fluid flow from the production zone to the earth's surface. Alternatively, in petroleum production, they may be used to control the flow of various fluids for stimulating or working a well from the earth's surface through the tubing string into the well annulus. Sliding sleeves are generally controlled from the earth's surface by wireline tools, or by other mechanisms known to those of ordinary skill in the art. In order for the sliding sleeve to function properly it is very important that the sliding components have a clean surface free of scale or deposits. In addition, for the sleeve to properly engage and disengage between different operating modes, it is important that the collet ribs and recesses which the ribs mate within are free of scale or deposits. As discussed herein, scale and other deposits can come out of solution or otherwise build up on the metallic parts resulting in sticking, galling or even inoperable downhole tools.

Gas lift valves are downhole tools used to increase recovery of fluids from wells with decreased hydrostatic pressure. Generally, for new producing formations, the pressure of the producing formation is greater than the hydrostatic pressure of the fluid in the wellbore, allowing the well to flow without artificial lift. However, as an oil bearing formation matures, and some significant percentage of the product is recovered, a reduction in the formation pressure occurs. With this reduction in formation pressure, the hydrocarbon issuance therefrom is likewise reduced to a point where the well no longer flows without assistance, despite the presence of significant volumes of valuable product still in place in the oil bearing stratum. In wells where this type of production decrease occurs, or if the formation pressure is low from the outset, artificial lift is commonly employed to enhance the recovery of oil from the formation.

In order for oil to be produced utilizing gas lift, a precise volume and velocity of the gas flowing upward through the tubing must be maintained. Gas injected into the hydrostatic column of fluid decreases the column's total density and pressure gradient, allowing the well to flow. As the tubing size increases, the volume of gas required to maintain the well in a flowing condition increases as the square of the increase in tubing diameter. If the volume of the gas lifting the oil is not maintained, the produced oil falls back down the tubing, and the well suffers a condition commonly known as "loading up." If the volume of gas is too great, the cost of compression and recovery of the lift gas becomes a significant percentage of the production cost. As a result, the size of a gas injection orifice in the gas lift valve is of crucial importance to the stable operation of the well.

In gas lift operations, high pressure injection gas enters the gas injection orifice or port in the valve body from the casing annulus and acts upon a bellows. When the combined force resulting from the injection gas pressure on the bellows area less the port area and the production pressure operating over the port area is greater than the force caused by the nitrogen charge within the bellows, the bellows is compressed and the valve stem tip is lifted off the valve seat, opening the valve. The injection gas flows through the seat and into the production tubing. When the pressure of the injection gas in the casing annulus at valve depth drops below the valve set pressure, the valve bellows extends downward, causing the ball of the stem tip to seat and close the valve. Reverse flow through the valve is prevented by an integral check valve in the nose of the valve body. For correct gas lift valve operation and for proper gas flow it is important that the portions of the outer surface of the valve body, the port, and the choke remain clean and free of scale or deposits that would interfere with the gas flow. It is also important that the integral check valve remain clean and free of scale or deposits that could interfere with it sealing tight against its seat. In addition to the scale and deposit problems associated with water or oil

well operations, some gas wells have high concentrations of corrosive hydrogen sulfide and/or carbon dioxide. Produced gas, including any corrosive gases present, may be used for gas lift operations. Therefore, corrosive conditions involving the hydrogen sulfide and/or carbon dioxide may result in additional fouling.

Many times downhole tools, known as subsurface locks, are attached to subsurface control devices such as safety valves, blanking plugs and standing valves. The subsurface lock anchors the valve or accessory in position in the tubing string. The subsurface lock and accessory are landed in an appropriate nipple by standard wireline methods. It is important that the depth of the subsurface lock placement be accurate to enable the valve or accessory to preform properly. It is also important to be able to attach a pulling tool to the subsurface lock when anchored valves or accessories need maintenance or replacement. Therefore, it is important that the fishing neck, the expander tube, the lock housing and locking dogs remain clean and free of scale or deposits that could interfere with the subsurface lock being properly placed or retrieved.

The reasons for scale, solids and other precipitates depositing within the well conduit are many and varied. Many well environments produce scale, wax, asphaltenes and other foulants. Highly unconsolidated well formations may slough loose, friable sands into the well conduit. Clays can be remineralized and deposit on surfaces. Bacterial growth can also occur, resulting in fouled surfaces. Workover fluids or corrosive gas well conditions can produce high corrosion rates on metal surfaces, resulting in corrosion product deposition. Operational problems such as ineffective or loss of viscosifying agents added to keep solids suspended in the produced fluids may result in solids deposition. Loss of annular velocity caused by the surface pump rate capability as well as torturous fluid paths or transient pressure drops within downhole tools may result in deposition of solids.

In addition to the above factors, for petroleum wells, the temperature and pressures found in the producing zone toward the bottom of the well are higher than those at the surface. Paraffins, waxes and asphaltenes may solidify when moving up the well conduit to the surface. Factors affecting the solidification or precipitation of these components as the oil moves toward the surface in the well conduit include their concentration in the produced oil, the temperature, the absolute pressure, and the rate of pressure drop through the well conduit which partially depends on the configuration and geometry of the fluid's flowpath. The point in the well conduit where the solidification or precipitation of these components generally occurs is broadly defined herein as the "deposition zone." In addition, in-situ clays found in the fluid may remineralize and deposit on downhole equipment.

Therefore, the art has sought a method for preventing, or reducing the rate of deposition of, scale, solids or other precipitates on downhole tool metallic surfaces and a downhole tool resistant to deposition of scale, solids, or other precipitates. Vicosifiers, foams, and other solids washing programs have been used to combat scaling and solids deposition problems in the well conduit. Specially formulated fluids which inhibit remineralization or hydration of in-situ clays have also been injected into the well. Corrosion inhibitors and special metallurgies have also been used to combat deposit of corrosion products. Pipe coatings have been used to control corrosion and to reduce friction losses. Downhole tools have also been coated to improve lubricity, and friction reduction through antistick properties of the selected coatings. However, the art continues to seek methods with the ability to prevent or reduce the rate of scaling and solids deposition, and downhole tools which are resistant to deposition of scale, solids, or other precipitates.

SUMMARY OF THE INVENTION

The present invention has been contemplated to prevent or reduce the rate of deposition of scale, solids or other precipitates on downhole tool metallic surfaces. The use of the term metallic surfaces, metallic parts or metallic portions in the specification and claims include, but is not limited to aluminum, steel, stainless steel, and nickel alloys. The downhole tool of the present invention has a plurality of metallic parts, at least one of the metallic parts having a portion of the part coated by a fluorinated ethylene propylene coating in a sufficient amount to impart anti-deposition properties to the metallic portions coated. The use of the term downhole tool in the specification and claims includes, but is not limited to, well completion tools, subsurface safety valves, gas lift valves, sliding sleeves, and subsurface locks. A feature of the present invention includes use of a fluorinated ethylene propylene coating with the ability to prevent or retard scale and solids deposition. The present invention may also include a resin primer, such as a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder to increase the ability of the anti-deposition coating to adhere to the metallic portions covered. In accordance with this aspect of the present invention, the fluorinated ethylene propylene coating may be applied over a perfluoroalkoxy copolymer resin primer to promote adhesion of the fluorinated ethylene propylene coating to the metallic part.

Another feature of the present invention is to thinly coat the metallic parts so that tool redesign is not required and so that coated replacement parts may be used with current designs. This foregoing advantage is achieved by limiting the coating thickness to a range from about 0.8 to about 2.0 mils dry film thickness. In a preferred embodiment of the present invention, the fluorinated ethylene propylene coating is applied over a perfluoroalkoxy copolymer resin containing a polyamide-imide binder such that the total coating has a thickness ranging from about 0.8 to about 2.0 dry mils.

Another feature of the present invention may include the use of a downhole tool for controlling fluid flow in a well conduit. The downhole tool with a plurality of metallic parts may be coated first with fluorinated ethylene propylene over a portion of at least one of the metallic parts of the downhole tool, the first coating having a thickness ranging from about 0.7 to about 0.9 mils dry film thickness with a topcoat or second coat of fluorinated ethylene propylene over the first coating, the second coating having a thickness ranging from about 0.2 to about 0.5 mils dry film thickness. The first coating may be of perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder.

In another specific embodiment, the metallic parts may be coated with polyphenylene sulfide (PPS) containing polytetrafluoroethylene (PTFE). In this embodiment, the thickness of the PPS and PTFE may be approximately 1.0 mil dry film thickness.

While the present invention may be used with any downhole tool, another aspect of the present invention includes well completion tools, subsurface safety valves, gas lift valves, sliding sleeves, and subsurface locks. Any metallic surface in the downhole tool may be coated as in the present invention. A further feature of the present invention for downhole tools with metallic seals includes coating at least a portion of at least one surface of the metallic seal. The coating of the metallic seal surfaces in accordance with the present invention, increases both its lubricity and its anti-deposition performance.

A further advantage of the present invention is to selectively coat surfaces that are subject to scaling and/or deposition of solids or subject to performance degradation if fouled by the scaling and/or deposition of solids. In accordance with this aspect of the present invention, at least a portion of the flow tube, the lockout-choke and the piston protector sleeve of the subsurface safety valves may be coated, each piece alone or in combination with the others. For gas lift valves, at least a portion of the plurality of outside surfaces, the fishing neck, the port in

the valve body, the integral check valve in the nose of the valve body and the choke, if present, may be coated, each surface alone or in combination with the others. For sliding sleeves, at least a portion of the inner sleeve, the collet ribs and recesses may be coated, each surface alone or in combination with the others. For subsurface locks, at least a portion of the fishing neck, the expander tube, the lock housing and locking dogs may be coated, each surface alone or in combination with the others.

The method of the present invention for controlling fluid production in a well conduit includes the steps of providing a downhole tool having a plurality of metallic parts; providing a fluorinated ethylene propylene coating over a portion of a least one of the metallic parts of the downhole tools wherein the coating is in a sufficient amount to impart anti-deposition properties to the metallic portions covered; and connecting the downhole tool to a tubing string forming a part of the well conduit. Another feature of the present invention may include the step of using a well completion tool. Still, another feature of the present invention may include the step of locating the downhole tool in a deposition zone of the well conduit. A further feature of the present invention may include the step of providing the fluorinated ethylene propylene coating over a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder. In another specific embodiment, the present invention may include the step of providing a coating of polyphenylene sulfide (PPS) containing polytetrafluoroethylene (PTFE).

BRIEF DESCRIPTION OF THE DRAWINGS

In the Drawings:

Figure **1** is an elevational side view, partially in cross-section, showing a subsurface safety valve of the present invention;

Figure **2** is an elevational side view, partially in cross-section, showing a lock-out choke, an option on a subsurface safety valve of the present invention;

Figures **3A** through **3C** are partial cross-sectional elevation views which together show a sliding sleeve of the present invention in a run-in position;

Figures **4A** and **4B** are partial cross-sectional elevation views which together show a sliding sleeve of the present invention in an open position;

Figure **5** is an elevational side view, partially in cross-section, showing a gas lift valve of the present invention;

Figure **6** is an elevational side view, partially in cross-section, showing a subsurface lock of the present invention in an unlocked position; and

Figure **7** is an elevational side view, partially in cross-section, showing a subsurface lock of the present invention in a locked position.

While the invention will be described in connection with the preferred embodiments, it will be understood that it is not intended to limit the invention to those embodiments. On the contrary, it is intended to cover all alternatives, modifications, and equivalents as may be included within the spirit and scope of the invention as defined by the appended claims.

DETAILED DESCRIPTION OF THE INVENTION

For purposes of the following description, it should be understood that the present invention can be used in any commercially available downhole tool, whether it is tubing conveyed, wireline conveyed, hydraulically operated, or electrically operated. The figures are not necessarily drawn to scale, and in some instances, have been exaggerated or simplified to clarify certain features of the invention. For the purposes of this discussion, the terms "upper" and "lower," "up hole" and "downhole," and "upwardly" and "downwardly" are relative terms to indicate position and direction of movement in easily recognized terms. Usually, these terms are relative to a line drawn from an upmost position at the surface to a point at the center of the earth, and would be appropriate for use in relatively straight, vertical wellbores. However, when

the wellbore is highly deviated, such as from about 60 degrees from vertical, or horizontal, these terms do not make sense and therefore should not be taken as limitations. These terms are only used for ease of understanding as an indication of what the position or movement would be if taken within a vertical wellbore. One skilled in the art will appreciate many differing applications of the described apparatus.

A feature of the present invention includes use of a substantially pure fluorinated ethylene propylene coating, free of dispersion agents, with ability to prevent or retard scale and solids deposition. The fluorinated ethylene propylene coating used may be, for example Xylan® 1756, available from Whitford Corporation headquartered in West Chester, Pennsylvania. The present invention may also include a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder to increase the ability of the anti-deposition coating to adhere to the metallic portions covered. Examples of this primer, Xylan® 1220 or Xylan® 1700, are also available from Whitford Corporation. In an alternative specific embodiment, the present invention may include use of a polyphenylene sulfide (PPS) coating containing polytetrafluoroethylene (PTFE), such as Xylan® 1331H, also available from Whitford Corporation. In a specific emodiment, the PPS/PTFE coating may have an approximate dry film thickness of 1.0 mil. The present invention may include a downhole tool for controlling fluid flow in a well conduit with a plurality of metallic parts and a fluorinated ethylene propylene coating over a portion of at least one of the metallic parts of the downhole tool formed by: applying a first coat of fluorinated ethylene propylene primer, the first coat having a thickness ranging from about 0.7 to about 0.9 mils dry film thickness; baking the primed tool at 400°F for five minutes; air cooling of the tool; applying a second coat of fluorinated ethylene propylene, the second coat having a thickness ranging from about 0.2 to about 0.5 mils dry film thickness; flashing the downhole tool at 200 °F for five minutes; baking the downhole tool at 750 °F for five minutes and air cooling the downhole tool.

In yet a more preferred embodiment of the present invention, for better adhesion of the anti-deposition coating, a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder may be substituted for the first coat of fluorinated ethylene propylene primer.

It will be assumed that for subsurface safety valves, the present invention is installed within a subsurface safety valve of the type shown in U.S. Patent No. 4,161,219, which type is commonly referred to as a rod-piston safety valve. Referring to the drawings in detail, wherein like numerals denote identical elements throughout the several views, there is shown in Figure 1 a specific embodiment of a subsurface safety valve **10** constructed in accordance with the present invention. With reference to Figure **1**, the subsurface safety valve **10** of this specific embodiment comprises a generally tubular body **12** with a longitudinal bore **14** that extends therethrough. Each end of the body **12** includes mechanisms, such as threads **16**, for interconnection with a pipe string (not shown) suspended within a wellbore (not shown). A sleeve member **18**, usually referred to as a flow tube, is disposed within the bore **14** and is adapted for axial movement therein. The flow tube **18** has an outer surface **19** which is subject to fouling by scaling or solids deposition. The flow tube **18** includes a spring **20** disposed therearound that acts upon a shoulder **22** on the flow tube **18** biasing the flow tube **18** away from a flapper mechanism **24**.

Still with reference to Figure **1**, the flapper mechanism **24** generally comprises a disc or flapper valve closure member **26** with an arm **28** on a peripheral edge thereof that is hingedly connected to an annular housing **30** mounted within the bore **14**. In a specific embodiment, the annular housing **30** includes a metallic annular sealing surface **32** cooperable with an annular sealing surface **34** on the flapper **26**. In a specific embodiment, the annular housing **30** may further include a secondary annular sealing surface **38** formed from an annular body of pliable

material, which is cooperable with the annular sealing surface **34** on the flapper **26**. The metallic sealing surface **32** is generally referred to as the "hard seat" and the pliable sealing surface **38** is generally referred to as the "soft seat."

As shown in Figure **1**, in a specific embodiment, a rod-piston system may be provided to open the flapper **26**, and may be comprised of a piston **40** sealably mounted for reciprocal movement within a cylinder **42** located within the wall of the tubular body **12**. A first end **41** of the piston **40** is in contact with hydraulic fluid (not shown) provided thereto from the earth's surface through a relatively small diameter control conduit **44**. A second end **43** of the piston **40** is operatively connected, in any suitable manner, to the flow tube **18**. When the pressure of hydraulic fluid in the control conduit **44** exceeds the force needed to compress the spring **20**, the piston **40** is forced downwardly, thereby causing the flow tube **18** to come into contact with, and open, the flapper **26**. The piston **40** is guided by a piston protector sleeve **59** as it moves axially. The outer surface **57** of the piston protector sleeve **59** is a surface subject to fouling by scaling or solids deposition. In the event that the hydraulic pressure applied to the piston **40** is decreased, as by command from the earth's surface or by the control conduit **44** being damaged, the spring **20** forces the flow tube **18** upwardly away from the flapper **26**. The flapper **26** is then rotated, and biased, into a closed position by action of a hinge spring (not shown) to permit the annular sealing surfaces **32, 34** and **38** to mate and thereby establish a fluid seal to prevent fluid flow into the flow tube **18**. A fluorinated ethylene propylene coating on the outer surface **19** of the flow tube **18** or the outer surface **57** of the piston protection sleeve **59** may eliminate or retard fouling with scale or deposited solids that could prevent the flapper **26** from actuating properly and prevent valve failure.

In reference to Figure **2**, in the life of a well it may be necessary to permanently lock a valve open. An option, known as a lock-out choke **55**, may be added to a subsurface safety valve to preform this function. In a specific embodiment, a choke sleeve member **56** is disposed within the inside diameter of a flow tube **18** and connected thereto by shear pins **60**. When it is desired to open a subsurface safety valve, the pressure of the hydraulic fluid in the control conduit (not shown) is increased until it exceeds the force needed to compress the spring **20**, whereby the piston **40** is forced downwardly. The downward motion of the piston **40** causes the flow tube **18** to force the choke sleeve member **56** downwardly into contact with, and open, the flapper **26**. When it is desired to permanently lock open the subsurface safety valve, a wire line shifting tool (not shown) is engaged with a profile **61** on the inner surface of the choke sleeve member **56** and used to mechanically apply downward forces to the choke sleeve member **56**. The downward jarring of the wireline tool (not shown) will shear each of the shear pins **60**, thereby separating the choke sleeve member **56** from the flow tube **18** and allowing the choke sleeve member **56** to travel downwardly towards the flapper **26**. This allows a snap ring **66** disposed about the choke sleeve member **56** to expand radially into engagement with a shoulder **62** formed in the annular housing **30**, thereby preventing upward movement of the choke sleeve member **56** and permanently locking the choke sleeve member **56** and flapper **26** in open positions. Scaling and/or solids deposition on the axially sliding surfaces of the choke sleeve member **56** and the flow tube **18** can prevent operation of the lock-out choke. A fluorinated ethylene propylene coating on the outer surface **68** of the choke sleeve member **56** and on the inner surface **70** of the flow tube **18** may prevent scaling and solids deposition that could interfere with the operation of the lockout choke **55**.

Figures **3A-3C** illustrate the sliding sleeve **110** in its initial or run-in configuration. Referring to Figure **3A**, in a specific embodiment, the sliding sleeve **110** of the present invention includes a housing **118** having a longitudinal bore **120** extending therethrough. An inner sleeve **122** is disposed for axial movement within the longitudinal bore **120**. A piston **124** is associated with the inner sleeve **122** and the longitudinal bore **120**. In a specific embodiment, the piston **124** may be sealably disposed around the inner sleeve **122** and within the longitudinal bore **120** of the housing **118**. The piston **124** is provided with an upper surface **124a**, a lower surface **124b**, an inner annular piston seal **124c**, an outer upper annular piston seal **124d**, and an outer lower annular piston seal **124e**. The inner annular piston seal **124c** is disposed between the inner sleeve **122** and the piston **124**. The outer annular piston seals **124d** and **124e** are disposed between the piston **124** and the housing **118**. At least one annulus pressure port **126** is provided through the housing **118** for exposing the piston **124** to pressure within an annulus (not shown) between the tubular conduit (not shown) and the casing (not shown). During the run-in mode, as shown in Figure **3A**, and before the sliding sleeve is first actuated: the piston **124** is releasably secured to the housing **118**, for example, by at least one shear pin **125**; the upper surface **124a** of the piston **124** is abutted against an upper shoulder **127** of the inner sleeve **122**; the lower surface **124b** of the piston is displaced above an annular shoulder **129** within the longitudinal bore **120** of the housing **118**; and the outer annular seals **124d** and **124e** are located above the at least one annulus pressure port **126**. The housing may also be provided with an annular housing seal **133** beneath the at least one shear pin **125** and above the annular shoulder **129**. The function of the housing seal **133** will be explained below.

Referring now to Figure **3B**, the housing **118** is provided with at least one outer fluid flow port **130**, and the inner sleeve **122** is provided with at least one inner fluid flow port **132**. An

upper annular flow port seal **134** is disposed above the at least one outer fluid flow port **130** and between the housing **118** and the inner sleeve **122**. Similarly, a lower annular flow port seal **136** is disposed below the at least one outer fluid flow port **130** and between the housing **118** and the inner sleeve **122**. A coating of fluorinated ethylene propylene on a least a portion of the outer surface **131** of the inner sleeve **122** may prevent or retard scaling and solids deposition that could interfere with the operation of the sliding sleeve **110**. In particular, a coating between the upper annular flow port seal **134** and the lower annular flow port seal **136**, where the inner sleeve **122** outer surface **131** is subject to scale and solids deposition could beneficially prevent or retard scaling and/or solids deposition. In a specific embodiment, the flow port seals **134** and **136** may be chevron packing, as well known to those of skill in the art. As will be more fully explained below, the at least one outer fluid flow port **130** and the at least one inner fluid flow port **132** sealably cooperate to control fluid flow between the annulus (not shown) and a longitudinal bore **123** through the inner sleeve **122**. Figure **3B** illustrates the fluid flow ports **130** and **132** in a closed or non-aligned relationship. In this position, fluid flow from the annulus (not shown) is prevented from flowing into the longitudinal bore **123** of the inner sleeve **122**. Further, the upper and lower annular seals **134** and **136** prevent fluid from migrating upwardly or downwardly in the annular space between the housing **118** and the inner sleeve **122**. The inner sleeve **122** may also be provided with at least one equalizing port **135** above the at least one flow port **132**. The function of the at least one equalizing port **135** will be explained below.

As shown in Figure **3C**, the lower end of the inner sleeve **122** is provided with a collet **138** having an annular rib, or collet, **140**. The longitudinal bore **120** through the housing **118** is provided with a number of annular recesses for receiving the collet rib **140**. In a specific embodiment, the bore **120** may be provided with an upper annular recess **142** (Figure 3B), an

intermediate annular recess **144**, and a lower annular recess **146**. In another embodiment, the bore **120** may also be provided with an equalizing recess **143** between the upper recess **142** and the intermediate recess **144**. The collet rib **140** is located in the intermediate recess **144** when the sliding sleeve **110** is in its run-in mode, as shown in Figures **3A-3C**. The relationship between the collet rib **140** and the upper, equalizing, and lower recesses **142**, **143**, and **146** will be described below. A fluorinated ethylene propylene coating on at least a portion, or preferably the entire surface, of the collet rib **140** and mating annular recesses **142-144, 146,** may prevent scaling and solids deposition that could interfere with the operation of the sliding sleeve **110.**

When it is desired to move the sliding sleeve **110** to its open position, as shown in Figure **4A-**

4B, to establish fluid communication through the fluid flow ports **130** and **132**, pressure is applied to the annulus (not shown), in any manner known to those of skill in the art. Referring to Figure **3A**, the annulus pressure is applied to the piston **124** through the at least one annulus pressure port **126**. The annulus pressure is contained by the inner piston seal **124c**, the outer lower piston seal **124e**, and the upper annular fluid flow port seal **134**, and acts upon the lower piston surface **124b** to force the piston **124** and the inner sleeve **122** upwardly. The force applied to the lower piston surface **124b** by the annulus pressure should be sufficient to (a) release the piston from the housing, for example, by shearing the at least one shear pin **125**, and (b) disengage the collet rib **140** from the intermediate recess **144** (not shown). Referring to Figure **4A**, the piston **124** and inner sleeve **122** cease upward movement when an upper surface **148** of the inner sleeve **122** abuts against an upper annular shoulder **150** within the longitudinal bore **120** of the housing **118**. When the inner sleeve **122** is in this uppermost position, the sliding sleeve **110** of the present invention is in its open position. As shown in Figure **4B**, opening the sliding

sleeve **110** brings the flow ports **130** and **132** into alignment and establishes fluid communication between the annulus (not shown) and the longitudinal bore **123** of the inner sleeve **122**. Fluids from the production zone (not shown) may then be produced to the earth's surface through the tubular conduit (not shown). The collet rib **140** is located in the upper recess **142** when the sliding sleeve **110** is in its open position.

If it is desired to equalize the pressure between the annulus (not shown) and the longitudinal bore **123** of the inner sleeve **122** — so as to avoid an initial rapid fluid flow through the flow ports **130** and **132** — the collet rib **140** may be moved into, and held in, the equalizing recess **143** prior to being moved into the upper recess **142**. This will move the inner sleeve **122** up to a point so that fluid communication is established from the at least one outer flow port **130** through the at least one equalizing port **135** but is not established through the at least one inner flow port **132**. After the pressure between the annulus (not shown) and the longitudinal bore **123** of the inner sleeve **122** is equalized through the at least one equalizing port **135**, the inner sleeve **122** may then be moved upwardly until flow ports **130** and **132** are aligned, as more fully explained above.

When it is desired to move the sliding sleeve **110** to its closed position, as shown in Figures **3A-3C**, to stop the flow of fluids from the production zone (not shown), a wireline shifting tool (not shown) is used to apply a downward impact force to the inner sleeve **122**, in a manner well known to those ordinarily skilled in the art. Fluid communication through the ports **130** and **132** will be fully terminated when the at least one flow port **132** in the inner sleeve **122** is moved below the lower flow port seal **136**. The sliding sleeve **110** will be fully closed, and the inner sleeve **122** will be in its lowermost position, when the collet rib **140** is located in the lower recess **146** (not shown). There is shown in Figure **5** a specific embodiment of a gas

lift valve **208** in the closed position constructed in accordance with the present invention. With reference to Figure **5**, the gas lift valve **208** of this specific embodiment comprises a generally tubular body **210** with a longitudinal bore **212** for sealable insertion in a side pocket mandrel (not shown). A bellows **218** located within the wall of the gas lift valve body **210** biases a valve stem **220** and ball **216** downwardly against the ball valve seat **222** into a closed position. The bellows **218** may be preset in any manner known to those of skill in the art before insertion into the side pocket mandrel (not shown) to the desired flowing pressure at the valve depth in the well conduit. When the combined force resulting from the injection gas pressure on the bellows area **218** less the injection gas pressure on the area of the ball **217** above the seat **222** and the production pressure operating over the area of the ball **219** below the seat **222** is greater than the force present within the bellows **218**, the bellows **218** is compressed. The bellows **218** lifts the valve stem **220** and ball **216** off the ball valve seat **222**, opening the valve **208** and allowing injection gas (not shown) to enter into the port **214** through the seat **222** and into the well conduit (not shown).

When the pressure of the injection gas in the casing annulus at the valve depth drops below the bellows set pressure, the bellows **218** expands causing the valve stem **220** and ball **216** to move downwardly, causing the ball **216** to seat in the ball valve seat **222**. Reverse flow through the valve body **210** is prevented by an integral check valve **224** located in the nose **226** of the valve body **210**. It is important that the check valve **224** remain free of any scale or deposits that could prevent it from sealing properly. Therefore, a fluorinated ethylene propylene coating on at least a portion, or preferably the entire surface of the integral check valve **224** may be useful in preventing or retarding scaling or solids deposition.

Optionally, the gas lift valve body **210** may house a choke **228** to control the maximum rate of gas through the gas lift valve **208**. The optional choke **228** may be housed in the nose **226** of the gas lift valve **208** as shown in Figure **5**, or alternatively, it may be located within the port **214**. Control of the quantities of injection gas (not shown) is required to balance the need to lighten the fluid column and allow the natural reservoir pressure to push the fluid up the well conduit and the operational costs associated with use of excessive quantities of injection gas. Careful sizing of the port **214** diameter in combination with use of a choke **228** or variable orifice facilitates this balance. Therefore, it is important to keep the gas flow path clean and free from scale or deposits in the areas designed to restrict and control the gas quantities. A fluorinated ethylene propylene coating on the interior annular port surface **215** and on the interior surface **230** of choke **228** may prevent scaling and solids deposition that could interfere with the control of the injection gas quantities. The gas lift valve body **210** may optionally include a fishing neck **234** for adapting the gas lift valve **208** to be remotely deployed and retrieved by standard methods known to those of skill in the art. It is important that the outer surface **235** of fishing neck **234** remain clean and free of scale or deposits that could interfere with the gas lift valve being properly retrieved. In addition, for gas lift valves inserted into side pocket mandrels (not shown), it is important that the portion of the outer surface contacting the mandrel, preferably the entire outer surface **232** of the gas lift valve body **210** to remain clear and free of scale or deposits to facilitate removal from the side pocket mandrels (not shown).

Referring now to Fig. **6**, a well locking device of the present invention is shown in a running mode, being lowered into a desired downhole position within the bore **334** of tubing **330** provided within a well. Running tool **320** is shown, having a shearable shear pin **342** or other retaining means **342** connecting the running tool to the housing **344** of the well lock **340**. Use

of a shearable shear pin **342** initially permits the well lock **340** to be lowered into the well bore **334** by lowering the running tool **320** attached thereto. The well lock **340** is lowered into the bore **334** of the tubing **330** until no-go shoulder **325** of the well locking device **310** abuts nipple landing shoulder **335** of the tubing **330** in a desired downhole portion **310** of tubing **330**. The no-go shoulder **325** and nipple landing shoulder **335** provided in connection with the well locking device **310** and tubing **330**, respectively, comprise bearing means, which prevent downhole movement of the well lock **340** when the well lock **340** has reached the proper location within tubing **330** for engagement thereof. However, it should be readily apparent to one of ordinary skill in the art that the no-go shoulder **325** and nipple landing shoulder **335** can be placed in various locations in connection with the well locking device **310** and the tubing **330** and other bearing means could be used. For example, a particular embodiment of the well locking device **310** of the present invention could incorporate a selective lock (not shown) having matching keys and recesses provided in connection therewith for proper placement of the well lock **340** within the tubing **330**. Other bearing means will also be readily recognized by those of ordinary skill in the art. In particular embodiments, such bearing means could be used in connection with certain aspects of the device and method of the present invention. Placement of the no-go shoulder **325** on the running tool **320** and not on the well lock housing **344** may increase the structural integrity of the well lock housing **344** and may eliminate the need for shearable or retractable no-go shoulders (not shown) on the well lock housing **344**, which may be provided in a particular embodiment to eliminate undesirable stresses on the well lock housing **344**.

After the well lock **340** is positioned within the desired downhole portion of the tubing **330**, and the well lock **340** is set, as described further hereinafter, an upward force may be applied to the running tool **320** to shear the shear pin **302**, thus separating the running tool **320**

from the well lock housing **344** and allowing the running tool **320** to be removed from the bore **335** of the tubing **330** after locking the well lock **340** in place. Shear pin **302** may be used to temporarily connect the running tool **320** to the well lock housing **344**. However, other retaining means may be provided, such as retractable fingers (not shown) provided in connection with the running tool **320,** to engage an inner groove such as recess **346** formed within expander tube **343** of the well lock **340**. In such an embodiment, when the running tool **320** is removed from the well lock **340**, the retractable fingers (not shown) may be retracted, thus disengaging the running tool **320** from the well lock **340** and permitting removal of the running tool **320** from the bore **335** of the tubing **330**.

At least a portion **328** of the setting portion **326**, or setting tool **326**, of the running tool **320** is provided in contact with at least a portion **348** of expander tube **343** of the well lock **340**. After the well lock **340** is positioned within the desired downhole portion of the tubing **330**, a downward pressure force may be applied to the setting portion **326**, or setting tool **326**, of running tool **320**, which may be resisted by abutment of the no-go shoulder **325** and nipple landing shoulder **335,** provided on the running tool **320** and the tubing **330**, respectively. The downward motion of setting portion **326**, or setting tool **320**, causes expander tube **343** of the well lock **340** to move downward within the well lock **340**. As shown in Fig. **6**, the well locking device **310** is initially located within the tubing **330** in a running mode, in which the locking dogs **345** of the well lock **340** are permitted to remain within the well lock **340** for lowering of the well lock **340** within the tubing **330**. The well lock **340** is maintained in the running mode by use of a shear ring **350** of the present invention, which is described in detail hereinafter.

In the running mode shown in Fig. **6**, at least a portion of shear ring **350** is disposed in a recess **347** formed or otherwise provided in a lower portion of expander tube **343** and at least

a portion of shear ring **350** is disposed within a corresponding upper recess **341** formed or otherwise provided in an upper portion of well lock housing **344**. When setting portion **326**, or setting tool **326**, of running tool **320** is forced downward, the shear ring **350** is sheared along a first shear plane **356**, as described hereinafter, thus permitting expander tube **343** to travel downward within the well lock housing **344** from a first, running, position, thus forcing locking dogs **345** outward from within well lock housing **344** to engage the locking dogs **345** within recess **332** formed or otherwise provided in the tubing **330**.

With reference now to Fig. 7, a continued downward force applied to expander tube **343** by setting portion **326**, or setting tool **326**, of running tool **320** may be applied to lower expander tube **343** to a second, locking, position, whereby outwardly biased shear ring **350**, as described further hereinafter, expands so that at least a portion of shear ring **350** remains disposed within the recess **347** formed or otherwise provided in expander tube **343** and at least a portion of shear ring **350** is disposed within a corresponding lower recess **342** formed or otherwise provided in a lower portion of well lock housing **344** of well lock **340**, thereby fully engaging locking dogs **345** within recess **332** of tubing **330** and locking the expander tube **343** in the second, locking position. Such locking of expander tube **343** in the locking position enables the well lock **340** to operate in its second, or locking mode, thereby locking the well lock **340** and any device affixed thereto (not shown) securely within the bore **334** of tubing **330**.

After setting the well lock **340** of the present invention in its locking mode within the bore **334** of tubing **330**, the running tool **320** and its associated setting portion **326**, or setting tool **326**, may be detached from the well lock **340** and removed from the bore **334** of tubing **330**, leaving the well lock **340** securely locked within the bore **334** of tubing **330**. In an embodiment wherein running tool **320** and well lock housing **344** are connected to one another by shear pin

302, the running tool 320 may be detached from the well lock 340 by providing an upward force on the running tool 320 sufficient to shear the shear pin 302 and thereby separate running tool 320 from well lock 340. The upward force is resisted by the locking dogs 345 engaged within the recess 332 formed or otherwise provided in the tubing 330. Thereafter, running tool 320 may be easily removed from the downhole portion of the tubing 330, leaving the well lock 340 locked in place within tubing 330.

When it is desired to remove the well lock 340 from within the bore 334 of tubing 330, a running removal tool, or pulling tool (not shown), may be provided having fingers adapted to engage the inner recess 346 formed in expander tube 343 of well lock 340. The running removal tool (not shown) may be lowered into the downhole portion of the well tubing bore 330 until it engages the expander tube 343. Thereafter, an upward force may be provided against the running removal tool (not shown) that is sufficient to shear the portion of the shear ring 350 engaged within the lower recess 342 of well lock housing 344. A continued upward force may thereafter be provided against the running removal tool (not shown) to raise the expander tube 343 from the second, locking, position within the well lock housing 344, returning the expander tube 343 to the first, running, position within well lock housing 344, which will permit locking dog 345 to be disengaged from the tubing recess 332 and permit the well lock 340 to be removed from the bore 334 of tubing 330. When the expander tube 343 is returned to the first, running, position within well lock housing 344, the well lock 340 is operable in its third, or pulling, mode. A continued upward force applied to the running removal tool (not shown) causes the expander tube 343 to abut a flange 315 formed as part of the fishing neck 365, located or other portion provided on the well lock housing 344 so that continued upward movement of the expander tube 343 will allow the well lock 340 to be removed from the downhole portion of the tubing bore

334. To eliminate or retard fouling with scale or deposited solids that could prevent the lock **340** from anchoring the valve or accessory in the proper position in the well conduit or that could prevent the lock **340** from being retrieved, a coating of fluorinated ethylene propylene is applied on a portion, or preferably the entire outer surface **367**, of the fishing neck **365**, expander tube **343**, well lock housing **344** and locking dogs **345**.

Whereas the present invention has been described in particular relation to the drawings attached hereto, it should be understood that other and further modifications, apart from those shown or suggested herein, may be made within the scope and spirit of the present invention. For example, any downhole tool that needs to be resistant to deposit of scale, solids or other precipitates may be coated, for example a landing nipple. In addition, the coating of the present invention is so thin that metallic replacement parts may be coated and inserted into current downhole tool designs as desired to retard or prevent scale and solids deposition. Accordingly, the invention is therefore to be limited only by the scope of the appended claims.

CLAIMS

1. A downhole tool for controlling fluid flow in a well conduit, comprising:

a plurality of metallic parts; and

a fluorinated ethylene propylene coating over a portion of at least one of the metallic parts of the downhole tool, wherein the coating is in a sufficient amount to impart anti-deposition properties to the metallic portions coated.

2. The downhole tool of claim **1**, including a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder, over which the fluorinated ethylene propylene coating is applied.

3. The downhole tool of claim **2**, wherein the primer and coating have a combined thickness ranging from about 0.8 to about 2.0 mils dry film thickness.

4. A downhole tool of claim **1**, wherein the coating has a thickness ranging from about 0.8 to about 2.0 mils dry film thickness.

5. The downhole tool of claim **1**, wherein the downhole tool is a well completion tool.

6. The downhole tool of claim **1**, wherein the downhole tool is a subsurface safety valve.

7. The downhole tool of claim 6, wherein the plurality of metallic parts include a flow tube, a lockout-choke and a piston protector sleeve.

8. The downhole tool of claim 7, wherein at least a portion of the flow tube is coated with the fluorinated ethylene propylene coating.

9. The downhole tool of claim 7, wherein at least a portion of the lockout-choke is coated with the fluorinated ethylene propylene coating.

10. The downhole tool of claim 7, wherein at least a portion of the piston protector sleeve is coated with the fluorinated ethylene propylene coating.

11. The downhole tool of claim 1, wherein the downhole tool is a gas lift valve.

12. The downhole tool of claim 11, wherein the plurality of metallic parts include a valve body with a plurality of outer surfaces, a fishing neck, a choke, a port disposed in the valve body, and a nose, the nose having an integral check valve disposed in the nose of the valve body.

13. The downhole tool of claim 12, wherein at least a portion of the outer surfaces of the valve body are coated with the fluorinated ethylene propylene coating.

14. The downhole tool of claim 12, wherein at least a portion of the fishing neck is coated with the fluorinated ethylene propylene coating.

15. The downhole tool of claim 12, wherein at least a portion of the port disposed in the valve body is coated with the fluorinated ethylene propylene coating.

16. The downhole tool of claim 12, wherein at least a portion of the choke is coated with the fluorinated ethylene propylene coating.

17. The downhole tool of claim 12, wherein at least a portion of the integral check valve disposed in the nose of the gas lift valve is coated with the fluorinated ethylene propylene coating.

18. The downhole tool of claim 1, wherein the downhole tool is a sliding sleeve.

19. The downhole tool of claim 18, wherein the plurality of metallic parts include an inner sleeve, having an outer surface, a plurality of collet ribs, and a housing having a longitudinal bore, wherein a plurality of recesses are disposed in the longitudinal bore.

20. The downhole tool of claim 19, wherein a least a portion of the outer surface of the inner sleeve is coated with the fluorinated ethylene propylene coating.

21. The downhole tool of claim 19, wherein a least one of the collet ribs is coated with the fluorinated ethylene propylene coating.

22. The downhole tool of claim 19, wherein a least a one of the recesses disposed in the longitudinal bore of the housing is coated with the fluorinated ethylene propylene coating.

23. The downhole tool of claim 1, wherein the downhole tool is a subsurface lock.

24. The downhole tool of claim **23**, wherein the plurality of metallic parts include a fishing neck, an expander tube, a lock housing, and a plurality of locking dogs.

25. The downhole tool of claim **24**, wherein at least a portion of the fishing neck is coated with the fluorinated ethylene propylene coating.

26. The downhole tool of claim **24**, wherein at least a portion of the expander tube is coated with the fluorinated ethylene propylene coating.

27. The downhole tool of claim **24**, wherein at least a portion of the lock housing is coated with the fluorinated ethylene propylene coating.

28. The downhole tool of claim **24**, wherein at least portion of one of the locking dogs is coated with the fluorinated ethylene propylene coating.

29. The downhole tool of claim **1**, wherein the plurality of metallic parts include at least one metallic seal having at least one surface coated with the fluorinated ethylene propylene coating.

30. The downhole tool of claim **1**, wherein the metallic parts coated with the fluorinated ethylene propylene coating have surfaces subject to scale or deposits.

31. The downhole tool of claim **1**, wherein the metallic parts coated with the fluorinated ethylene propylene have surfaces subject to performance degradation by scale or deposits.

32. A downhole tool for controlling fluid flow in a well conduit, comprising:

a plurality of metallic parts; and

a polyphenylene sulfide coating containing polytetrafluoroethylene over a portion of at least one of the metallic parts of the downhole tool, wherein the coating is in a sufficient amount to impart anti-deposition properties to the metallic portions coated.

33. The downhole tool of claim **32**, wherein the polyphenylene sulfide coating containing polytetrafluoroethylene has a thickness of approximately 1.0 mil dry film thickness.

34. A method of controlling fluid production in a well conduit, comprising the steps of:

(a) providing a downhole tool having a plurality of metallic parts;

(b) providing a fluorinated ethylene propylene coating over a portion of at least one of the metallic parts of the downhole tool wherein the coating is in a sufficient amount to impart anti-deposition properties to the metallic portion covered; and

(c) connecting the downhole tool to a tubing string forming a part of the well conduit.

35. The method of claim **34**, wherein the downhole tool is a well completion tool.

36. The method of claim **34**, including the step of locating the downhole tool in a deposition zone of the well conduit.

37. The method of claim **34**, including the step of providing the fluorinated ethylene propylene coating over a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder.

38. A method of controlling fluid production in a well conduit, comprising the steps of:

(a) providing a downhole tool having a plurality of metallic parts;

(b) providing a polyphenylene sulfide coating containing polytetrafluoroethylene over a portion of at least one of the metallic parts of the downhole tool wherein the coating is in a sufficient amount to impart anti-deposition properties to the metallic portion covered; and

(c) connecting the downhole tool to a tubing string forming a part of the well conduit.

39. The method of claim **38**, further including the step of providing the polyphenylene sulfide coating containing polytetrafluoroethylene in an approximate dry film thickness of 1.0 mil.

40. A downhole tool for controlling fluid flow in a well conduit, comprising:

a plurality of metallic parts;

a first coating of fluorinated ethylene propylene over a portion of at least one of the metallic parts of the downhole tool, the first coating having a thickness ranging from about 0.7 to about 0.9 mils dry film thickness; and

a second coating of fluorinated ethylene propylene over the first coating, the second coating having a thickness ranging from about 0.2 to about 0.5 mils dry film thickness.

41. The downhole tool of claim **40**, wherein the first coating is of perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder.

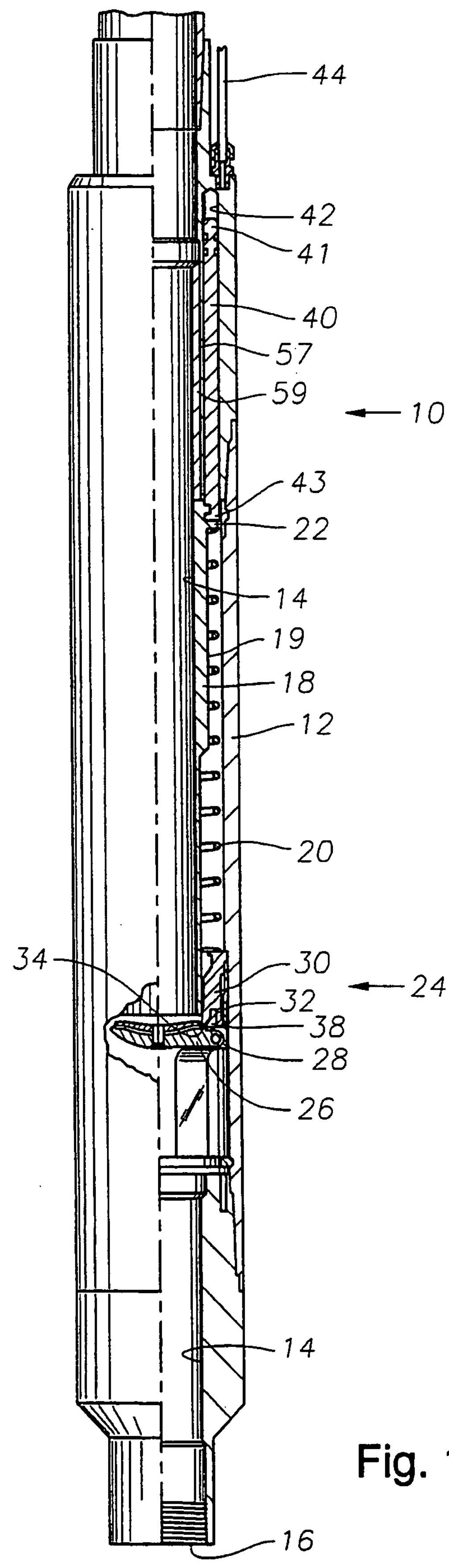


Fig. 1

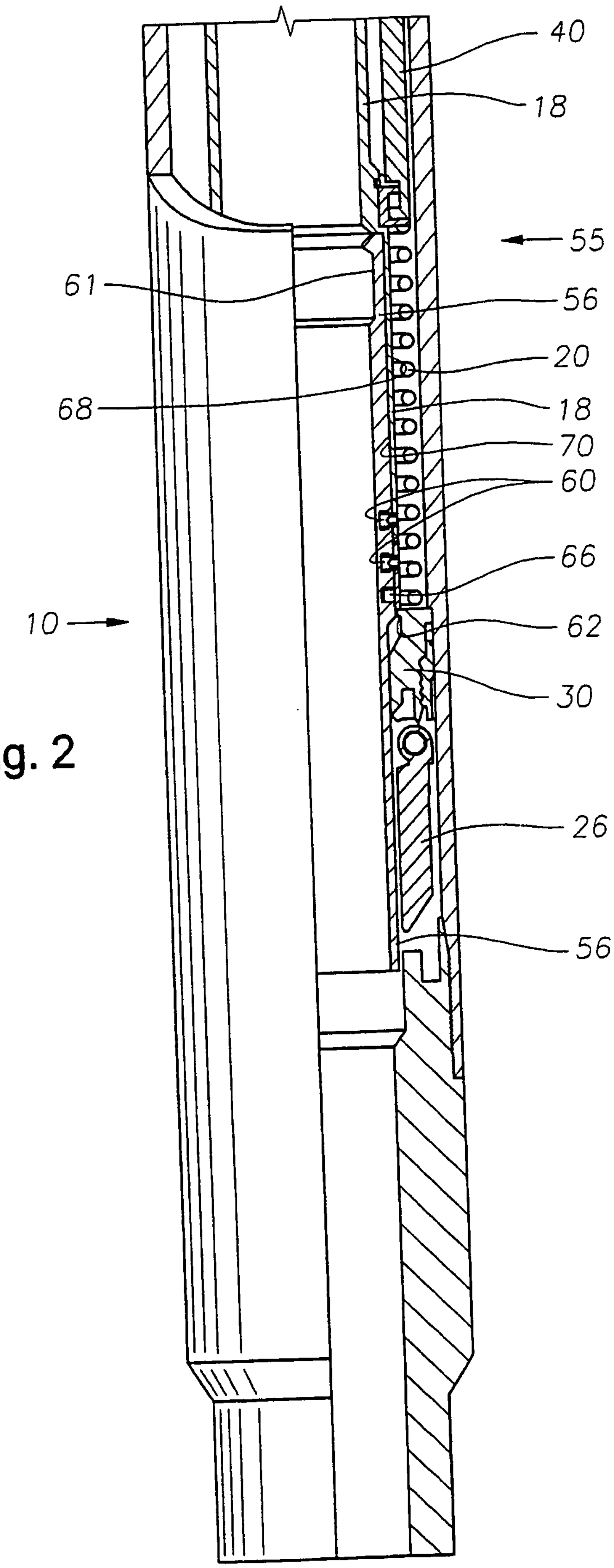
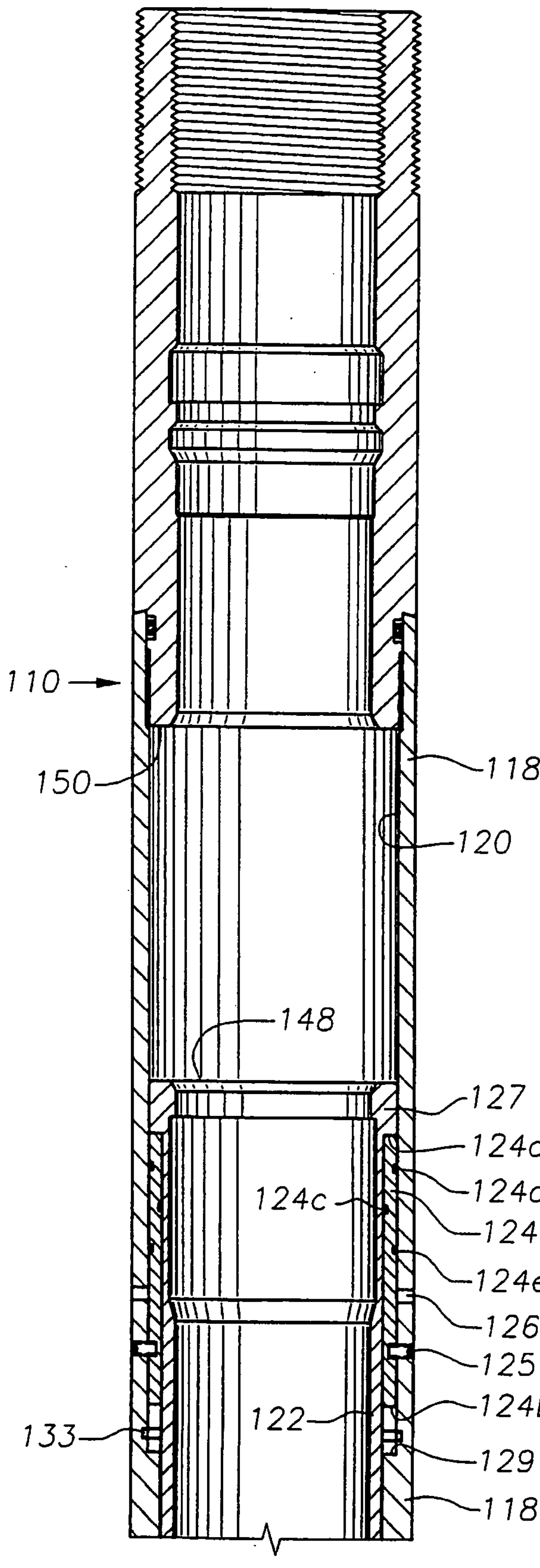


Fig. 2



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124b
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Fig. 3A

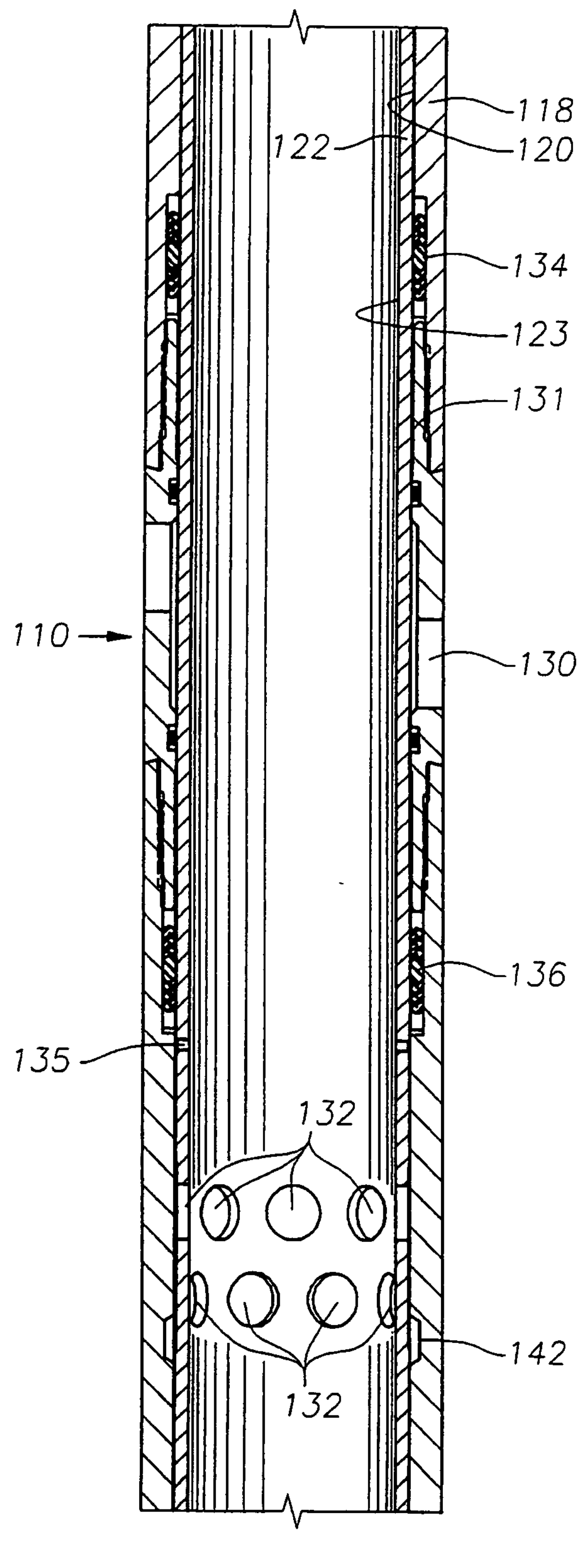

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Fig. 3B

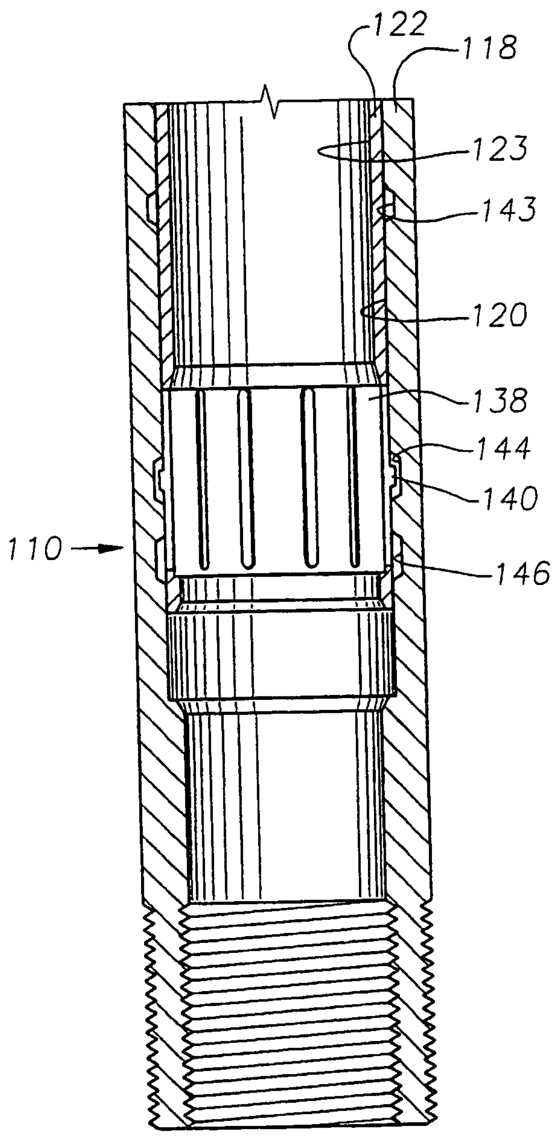
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Fig. 3C

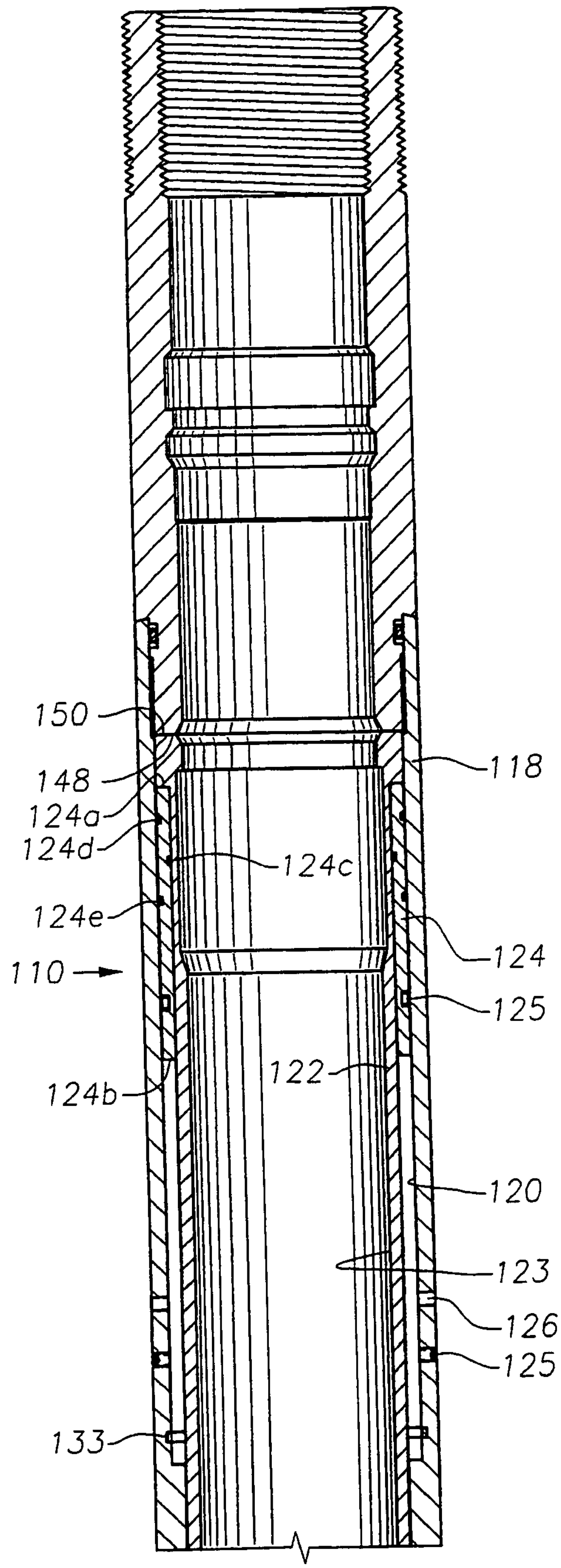
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Fig. 4A

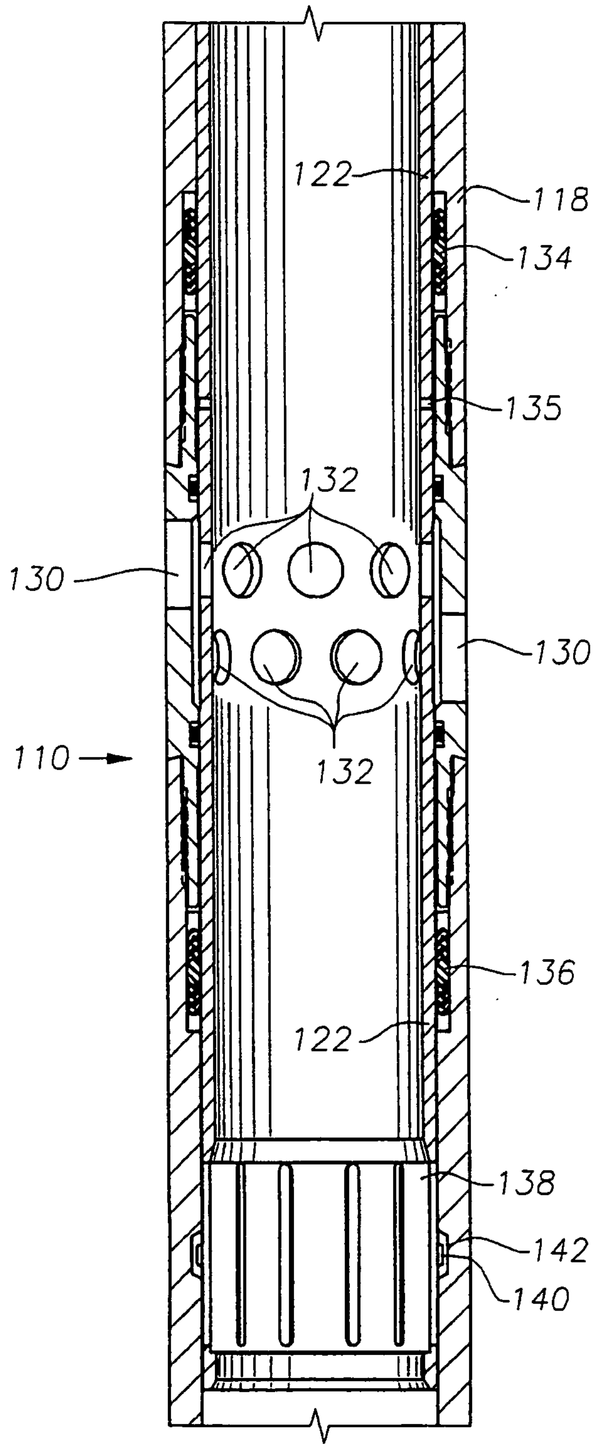
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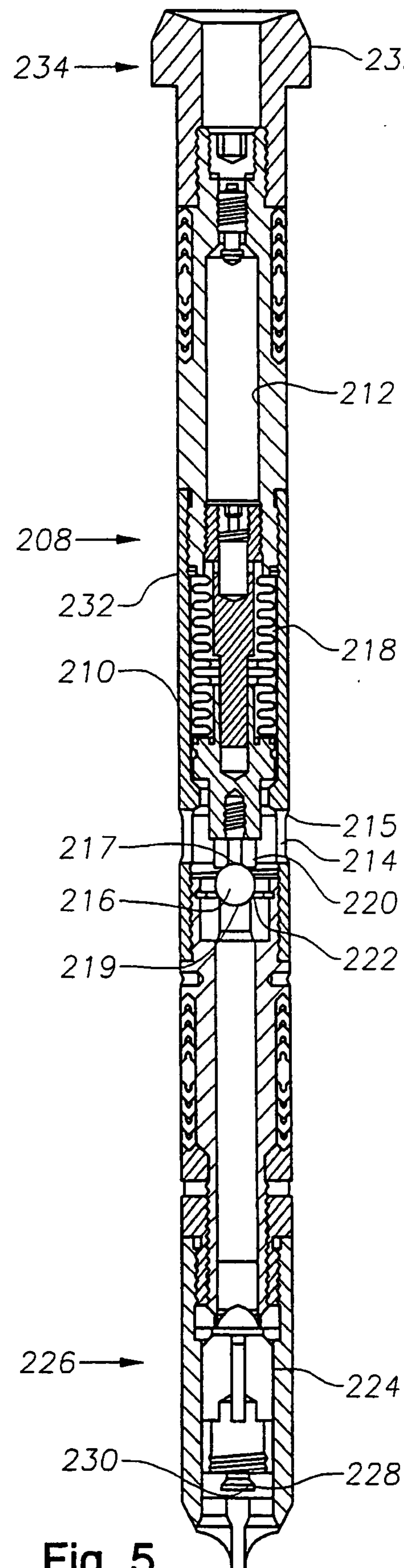
Fig. 4B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228

Fig. 5

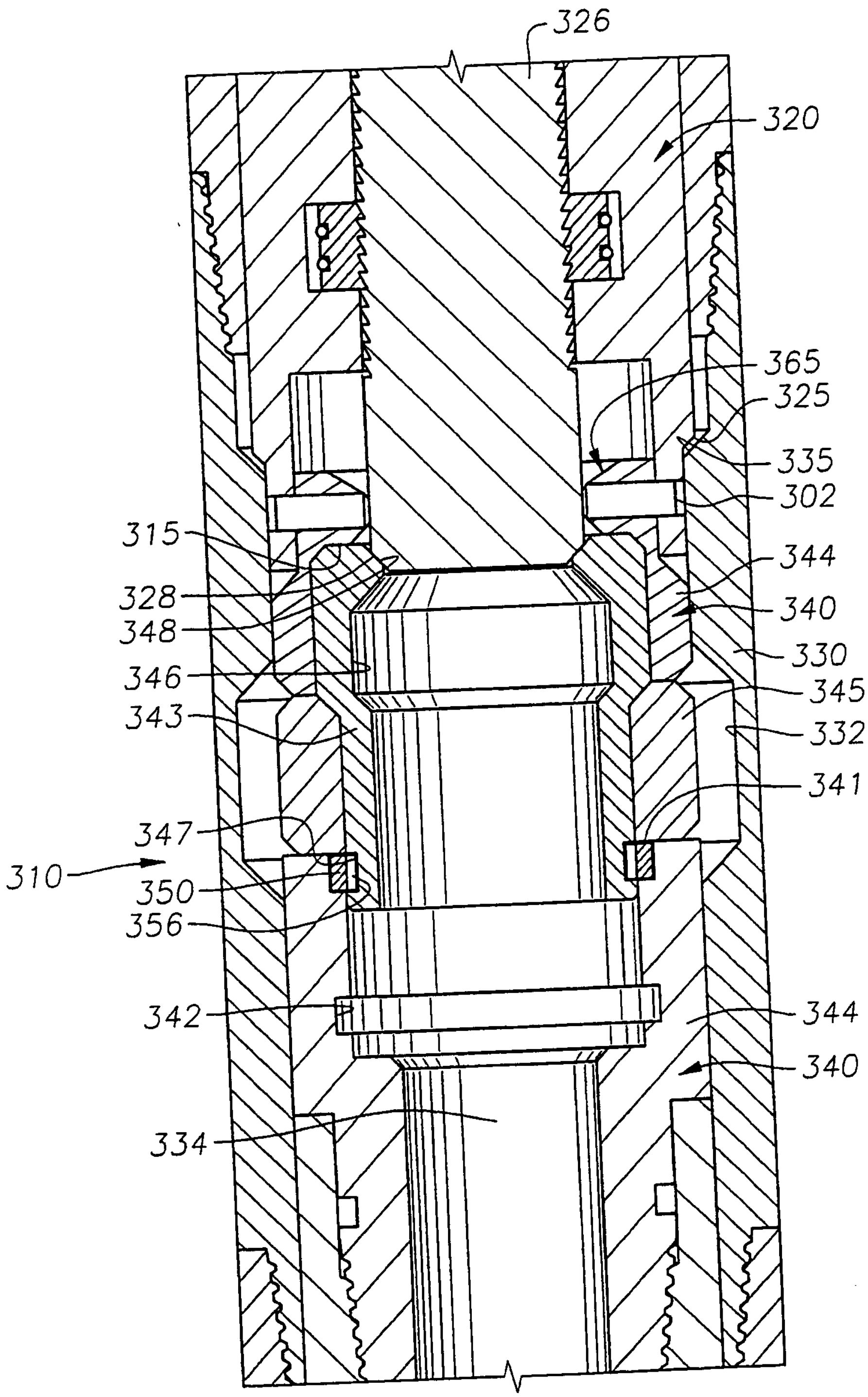
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Fig. 6

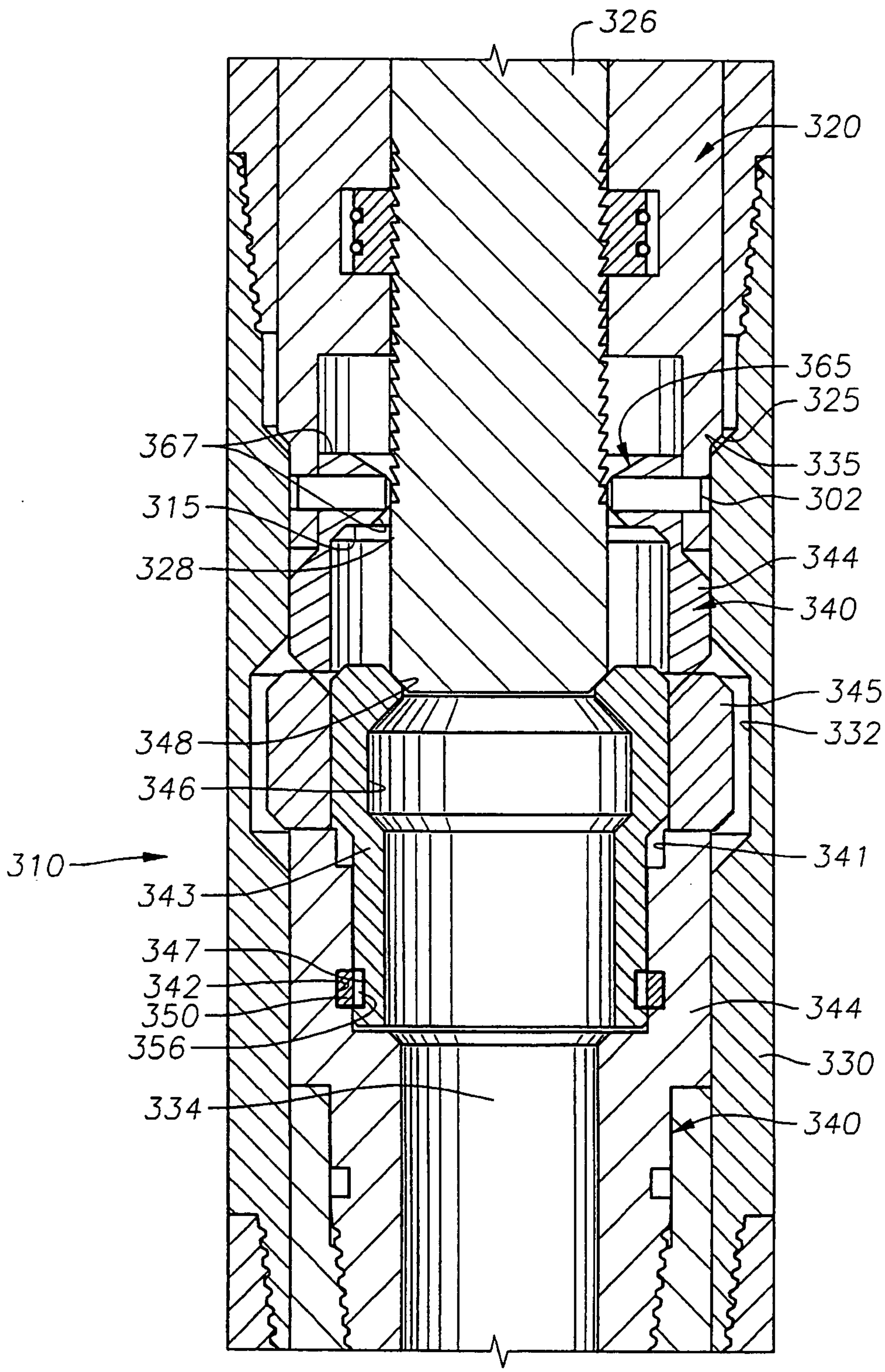
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Fig. 7

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US99/07852

A. CLASSIFICATION OF SUBJECT MATTER

IPC(6) :E21B 37/06
US CL :166/304
According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

U.S. : 166/242.4, 304, 310, 371, 902

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

APS
search terms: fluorinated ethylene propylene or FEP, polyphenylene sulfide or PPS, coat###

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 5,105,879 A (ROSS) 21 April 1992 (21/04/92), see entire document, especially figure 5 and column 5.	1, 4, 5-31, 34-36, 40
X	US 4,671,833 A (BRADFORD et al.) 09 June 1987 (09/06/87), see entire document, especially column 4.	1,5-31, 34-36, 40
A	US 4,905,760 A (GRAY) 06 March 1990 (06/03/90), see entire document, especially columns 10 and 11.	32, 33, 38, 39
A	US 4,349,050 A (BERGSTROM et al.) 14 September 1982 (14/09/82), see entire document, especially column 3.	32, 33, 38, 39

☐ Further documents are listed in the continuation of Box C. ☐ See patent family annex.

* Special categories of cited documents:

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier document published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
21 MAY 1999	16 JUN 1999

Name and mailing address of the ISA/US	Authorized officer
Commissioner of Patents and Trademarks Box PCT Washington, D.C. 20231	ZAKIYA WALKER Diane Smith for
Facsimile No. (703) 305-3230	Telephone No. (703) 305-0302

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US99/07852

Box I Observations where certain claims were found unsearchable (Continuation of item 1 of first sheet)

This international report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:
because they relate to subject matter not required to be searched by this Authority, namely:

2. ☐ Claims Nos.:
because they relate to parts of the international application that do not comply with the prescribed requirements to such an extent that no meaningful international search can be carried out, specifically:

3. ☐ Claims Nos.:
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

Box II Observations where unity of invention is lacking (Continuation of item 2 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

Please See Extra Sheet.

1. ☒ As all required additional search fees were timely paid by the applicant, this international search report covers all searchable claims.

2. ☐ As all searchable claims could be searched without effort justifying an additional fee, this Authority did not invite payment of any additional fee.

3. ☐ As only some of the required additional search fees were timely paid by the applicant, this international search report covers only those claims for which fees were paid, specifically claims Nos.:

4. ☐ No required additional search fees were timely paid by the applicant. Consequently, this international search report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:

Remark on Protest
☐ The additional search fees were accompanied by the applicant's protest.
☐ No protest accompanied the payment of additional search fees.

BOX II. OBSERVATIONS WHERE UNITY OF INVENTION WAS LACKING
This ISA found multiple inventions as follows:

This application contains the following inventions or groups of inventions which are not so linked as to form a single inventive concept under PCT Rule 13.1. In order for all inventions to be searched, the appropriate additional search fees must be paid.

Group I, claim(s)1-31, 34-37, and 40-41, drawn to a downhole tool comprising metallic parts having fluorinated ethylene propylene coating and method of use.

Group II, claim(s) 32, 33, 38, and 39, drawn to a downhole tool comprising metallic parts having polyphenylene sulfide coating and method of use.

The inventions listed as Groups I and II do not relate to a single inventive concept under PCT Rule 13.1 because, under PCT Rule 13.2, they lack the same or corresponding special technical features for the following reasons: Two products and processes of use are claimed.